

Adams, Hope

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Sent: Monday, July 26, 2021 2:48 PM
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Cc: PSC_Contact; Besley, Sharon
Subject: RE: Hearing Exhibit #10 (Cross Examination Exhibit) -- DN 2020-263-E
Attachments: DEC DEP Strunk Cross Exhibit 3.PDF

Parties:

Attached is a copy of the Cross Examination Exhibit of Duke regarding Witness Hanson.

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**BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA**

DOCKET NO. 1995-1192-E

In the Matter of:)	
)	APPLICATION OF DUKE ENERGY
Proceeding for Approval of the Public)	CAROLINAS, LLC AND DUKE
Utility Regulatory Policies Act of 1978)	ENERGY PROGRESS, LLC FOR
(PURPA) Avoided Cost Rates for)	APPROVAL OF UPDATED
Electric Companies)	STANDARD OFFER AVOIDED
)	COST RATES AND TARIFFS

Pursuant to S.C. Code Ann. § 58-3-140 and 26 S.C. Code Ann. Regs. 103-303 and 103-823 and other applicable rules and regulations of the Public Service Commission of South Carolina ("Commission"), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies"), by and through counsel, hereby petition the Commission for approval of DEC's and DEP's updated Schedule PP tariffs ("Schedule PP"), including revised Terms and Conditions and the standard purchased power agreement ("PPA") in support of Schedule PP. This Application, together with the exhibits included herewith, presents the Companies' updated avoided cost rates that are being made available to all qualifying cogenerators and small power production facilities ("QFs") that meet the eligibility requirements set forth in DEC's and DEP's respective Schedule PP and commit to sell their output to DEC or DEP on or after the date of this filing. The Companies' Schedule PP avoided cost rates and terms presented herein have been designed to meet the requirements of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the Federal Energy Regulatory Commission's ("FERC") regulations implementing those provisions, as well as prior orders issued by this Commission implementing PURPA.

Through this Application, DEC and DEP are seeking Commission approval to update the Companies' respective avoided cost calculations to ensure the rates paid to QFs by the Companies' customers remain just and reasonable for the Companies' customers and comply with PURPA's avoided cost standards by accurately reflecting the Companies' future capacity and energy costs that can be avoided through QF purchases. The Companies' updated avoided cost rates recognize each utility's most current integrated resource planning determination of future capacity needs, and take into account the recent, significant declines in the forecasted cost

of energy due to declining natural gas prices. Schedule PP will continue to be available to QFs up to 2 megawatts (“MW”) in size, and will continue to offer the previously-available variable, 5-year, and 10-year term options.

Schedule PP has been modified to incorporate updated energy and capacity rate designs that better recognize the differing value of QF capacity and energy during on-peak and off-peak periods during each day and throughout the year. The Companies have also included an integration services charge specific to solar QFs to recognize the increasing cost to operate the Companies’ dispatchable generating fleets as growing levels of variable and non-dispatchable solar capacity are added to the DEC and DEP systems. Finally, the Companies are updating the Terms and Conditions applicable to QFs selling power under Schedule PP to (i) make clear the Companies’ right to curtail QF energy output and discontinue purchases from QFs in imminent “emergency conditions,” specifically including where curtailment is necessary to ensure compliance with mandatory North American Electric Reliability Corporation (“NERC”) and SERC Reliability Corporation (“SERC”) standards; and (ii) ensure customers are not disadvantaged by QF developers potentially seeking to circumvent the Schedule PP eligibility requirements or to modify their operating QF generating facility in order to sell greater output at older standard offer rates in excess of the Companies’ current avoided costs.

Due to the commercial sensitivity and proprietary nature of certain information being filed in support of this Application, the Companies respectfully request that the Commission find that pursuant to S.C. Code Ann. § 30-4-40(a), DEC Exhibit 3 and DEP Exhibit 3 are exempt from disclosure under the Freedom of Information Act, S.C. Code Ann. §§ 30-4-10 *et seq.* and 10 S.C. Code Ann. Regs. § 103-804(S)(1). The information contained in DEC Exhibit 3 and DEP Exhibit 3 reflects the Companies’ costs to procure additional energy and/or capacity. The

wholesale electricity market is extremely competitive, and in order for the Companies to obtain the most cost-effective energy and capacity to meet the needs of their customers, they must protect from public disclosure their projected and actual cost to procure such energy, capacity, or both. In addition, if this information was publicly available, potential suppliers would know the price against which they must bid, and rather than bidding the lowest price possible, they would simply bid a price low enough to beat the Companies' projections.

Accordingly, the Companies are filing the confidential version of DEC Exhibit 3 and DEP Exhibit 3 to the Application under seal and respectfully request that the Commission maintain this information as confidential pursuant to Order No. 2005-226, "Order Requiring Designation of Confidential Materials." Enclosed with this Application is a redacted version of the Application that protects the Companies' commercially sensitive and proprietary information being filed under seal. Additionally, the Companies are hand delivering to the Commission and Office of Regulatory Staff ("ORS") copies of the confidential version of these exhibits.

In support of the Companies' Application, DEC and DEP respectfully show unto the Commission the following:

1. The Companies' general offices are at 550 South Tryon Street, Charlotte, North Carolina, and their mailing address is:

Duke Energy Progress, LLC
410 South Wilmington Street
Raleigh, North Carolina 27601-1849

Duke Energy Carolinas, LLC
PO Box 1321 (DEC 45A)
Charlotte, North Carolina 28201-1006

2. Legal counsel for the Companies in this proceeding are as follows:

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and

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3. Copies of all pleadings, testimony, orders, and correspondence in this proceeding should be served upon the attorneys listed above.

I. INTRODUCTION AND BACKGROUND ON PURPA STANDARD OFFER TARIFF

a. PURPA's Must Purchase Obligation and the Standard Offer Requirements

4. Pursuant to Sections 201 and 210 of PURPA, electric utilities such as DEC and DEP are required to offer to purchase electric energy from qualifying cogeneration and small

¹ Mr. Breitschwerdt is not admitted to practice in South Carolina and is seeking authorization to appear *pro hac vice* before the Commission in this proceeding.

power production facilities or QFs.² PURPA requires that the rates electric utilities pay to purchase QF energy shall not exceed the electric utilities' "avoided costs," which PURPA defines as the cost to the electric utility of the electric energy, which, but for the purchase from such QFs, such utility would generate or purchase from another source.³ In addition to the requirement that such rates not be more than the electric utility's avoided costs, PURPA also requires that the rates for purchases of QF power be set at levels and in a manner that is just and reasonable to the utility's customers, in the public interest, and nondiscriminatory towards QFs.⁴

5. In enacting PURPA, Congress directed FERC to prescribe regulations to encourage the development of QFs under PURPA, and delegated to State Commissions and non-regulated public utilities the responsibility of implementing FERC's regulations, including PURPA's "must purchase" obligation.⁵ FERC specifically established regulations relating to electric utilities' obligations to purchase power from, sell power to, and interconnect with QFs, as well as regulations establishing a general framework for setting the rates for purchase at the utility's avoided cost.⁶

6. In establishing regulations to implement PURPA, FERC's 1980 rulemaking order, Order No. 69, recognized that smaller QFs could be challenged by the transactional costs of bilaterally negotiating individualized rates with electric utilities, and required States implementing PURPA to make standard rates and terms available to QFs that are 100 kilowatts

² See 16 U.S.C. § 824a-3(a).

³ 16 U.S.C. § 824a-3(b), (d).

⁴ 16 U.S.C. § 824a-3(b)(1); (2).

⁵ See 16 U.S.C. § 824a-3(f); see also *FERC v. Mississippi*, 456 U.S. 742, 750-51, 102 S.Ct. 2126 (1982).

⁶ See 18 C.F.R. § 292.101(b)(6); 18 C.F.R. § 292.303; 18 § C.F.R. 292.304.

("kW") and smaller.⁷ FERC's regulations also provide that States "may" put into effect standard rates for purchases for QFs larger than 100 kW, explaining "that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates *accurately reflect the costs* that the utility can avoid as a result of such purchases."⁸ Thus, in setting the mandatory purchase obligation requirements under its regulations, FERC mandated that standard avoided cost rates should be made available to small QF generators of 100 kW or less, while leaving it to the implementing State Commission to determine whether to set standardized avoided cost rates for QF generators sized greater than 100 kW.

7. States may comply with FERC's regulations and Congress' direction to implement the PURPA purchase obligation "by issuing regulations, by resolving disputes on a case-by-case basis, or by taking any other action reasonably designed to give effect to FERC's rules."⁹ Importantly, FERC has also recognized that states have flexibility in implementing PURPA's "must purchase" requirements, so long as the State's implementation is reasonably consistent with PURPA and FERC's implementing regulations.¹⁰ This is because the States are best suited to consider and balance PURPA's goals with the "economic and regulatory circumstances [that] vary from State to State and utility to utility."¹¹

⁷ See *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, at 12,223, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69"); 18 C.F.R. § 292.304(c).

⁸ Order No. 69, at 12,223 (emphasis in the original).

⁹ See 456 U.S. at 751,102 S.Ct. 2126. See also *Policy Statement Regarding Comm'n's Enforcement Role Under Sec. 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC ¶ 61,304, 61,644 (1983).

¹⁰ See Order No. 69, at 12,232.

¹¹ Order No. 69, at 12,231.

8. Since the 1980s, this Commission has implemented PURPA by overseeing and approving DEC's and DEP's standard offer tariffs, while allowing the Companies and larger QFs to negotiate purchased power contracts at the Companies' avoided costs. Specifically, in Order No. 81-214,¹² the Commission approved Duke Power Company's (now DEC) and Carolina Power & Light's (now DEP) standard offer tariffs establishing standard rates, terms, and conditions to be offered to QF projects up to 5 MW in size for a term of 5 years.¹³ The Commission also recognized utilities and larger QFs could negotiate contracts, pursuant to the full avoided cost standard established by FERC's PURPA regulations.¹⁴

9. DEC and DEP both retained the 5-year standard offer term and short-term variable rate structures available to QFs up to 5 MW from 1981 until the Commission's most recent approval of the Companies' respective Schedule PP tariffs in 2016.

b. The Companies' pre-existing Schedule PP standard offer tariffs have significantly encouraged solar QF development since 2016

10. The Companies' pre-existing Schedule PP and corresponding Terms and Conditions were approved by the Commission in Order No. 2016-349, issued in May 2016, and became effective June 1, 2016. In that proceeding, the Commission approved the Companies' Schedule PP and fixed the Companies' avoided costs rates based upon the avoided energy and capacity calculations that had most recently been reviewed and approved by the North Carolina Utilities Commission ("NCUC") in NCUC Docket No. E-100, Sub 140.¹⁵ Additionally, the

¹² *In re: Small Power Production and Cogeneration Facilities – Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 81-214 (Mar. 20, 1981) ("Order No. 81-214").

¹³ See Order No. 81-214, at 8.

¹⁴ See Order No. 81-214, at 9, 20.

¹⁵ *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, NCUC Docket No. E-100, Sub 140 (Dec. 31, 2015) ("NC Sub 140 Standard Offer Rate Order").

Commission approved the eligibility for Schedule PP that became effective June 1, 2016, at 2 MW or less, and provided that those eligible QFs should be offered variable, 5-year, and 10-year contract term options.¹⁶

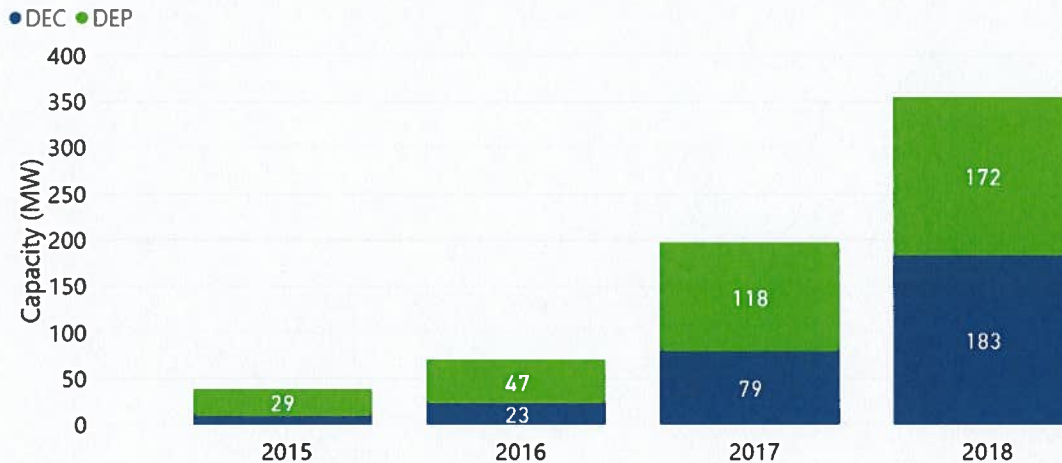
11. The Schedule PP avoided cost rates approved by the Commission in 2016 were in effect for approximately two and one-half years. During this period, the Companies experienced unprecedented solar QF development in their service territories across South Carolina. Approximately 155 solar QF projects totaling approximately 305 MW established legally enforceable commitments to sell their output to DEC and DEP under the pre-existing Schedule PP rates during this period. Of these QF projects, 22 projects comprising approximately 44 MW are now under construction and anticipate delivering power later in 2018 or in 2019. Notably, this recent surging QF development under the pre-existing Schedule PP standard offer tariff has been “solar only” and has not reflected more diversified development of other QF technologies that are also eligible for Schedule PP. This recent QF development has also nearly all occurred precisely at 2.0 MW, with 152 of the total 155 projects being developed between 1.90 MW and 2 MW.

Figure 1 presents year-to-year aggregate growth in QF development within DEC and DEP for those QFs sized 2 MW and below (and therefore eligible for Schedule PP).

¹⁶ In prior settlements related to DEC’s and DEP’s Distributed Energy Resource Programs, DEC and DEP both agreed to modify their respective standard offer tariffs to adjust the eligibility for the standard offer from 5 MW to 2 MW and to extend the 5-year term to a 10-year term. The Commission approved both settlements. *Order Addressing Distributed Energy Resource Program and Approving Settlement Agreement*, Order No. 2015-514, Docket No. 2015-53-E (July 15, 2015); *Order Addressing Distributed Energy Resource Program and Approving Settlement Agreement*, Order No. 2015-515, Docket No. 2015-55-E (July 15, 2015).

Figure 1¹⁷**SC Standard Offer Interconnection Requests for QFs \leq 2 MW**

Cumulative Capacity As of October 31, 2018



12. The recent surging growth of solar QFs committing to sell their output under the Companies' pre-existing Schedule PP far exceeds DEC's and DEP's utility-scale Act 236 goals¹⁸ and shows that the Companies' current avoided cost framework has significantly encouraged QF growth under PURPA in South Carolina. Compared to other states in the Southeast, only North Carolina has implemented PURPA policies that have fostered such significant "solar only" QF development in such a short period of time.¹⁹ However, due to concerns of customer

¹⁷ Figure 1 identifies the total capacity of all projects sized 2 MW and below that submitted Interconnection Requests through October 31, 2018. Some of these projects have not legally committed to sell power to the Companies under Schedule PP and therefore are not included in the 305 MW described in Paragraph 11 as establishing legally enforceable commitments.

¹⁸ Act 236 requires DEC and DEP to develop by 2021, renewable energy facilities located in South Carolina greater than 1 MW but no greater than 10 MW in an aggregated amount of installed nameplate generation capacity equal to one percent of the previous five-year average of the electrical utility's South Carolina retail peak demand, which equates to approximately 40 MW for DEC and 13 MW for DEP. S.C. Code Ann. § 58-39-130(C)(1); *Order Addressing Distributed Energy Resource Program and Approving Settlement Agreement*, Order No. 2015-514, Docket No. 2015-53-E (July 15, 2015); *Order Addressing Distributed Energy Resource Program and Approving Settlement Agreement*, Order No. 2015-515, Docket No. 2015-55-E (July 15, 2015).

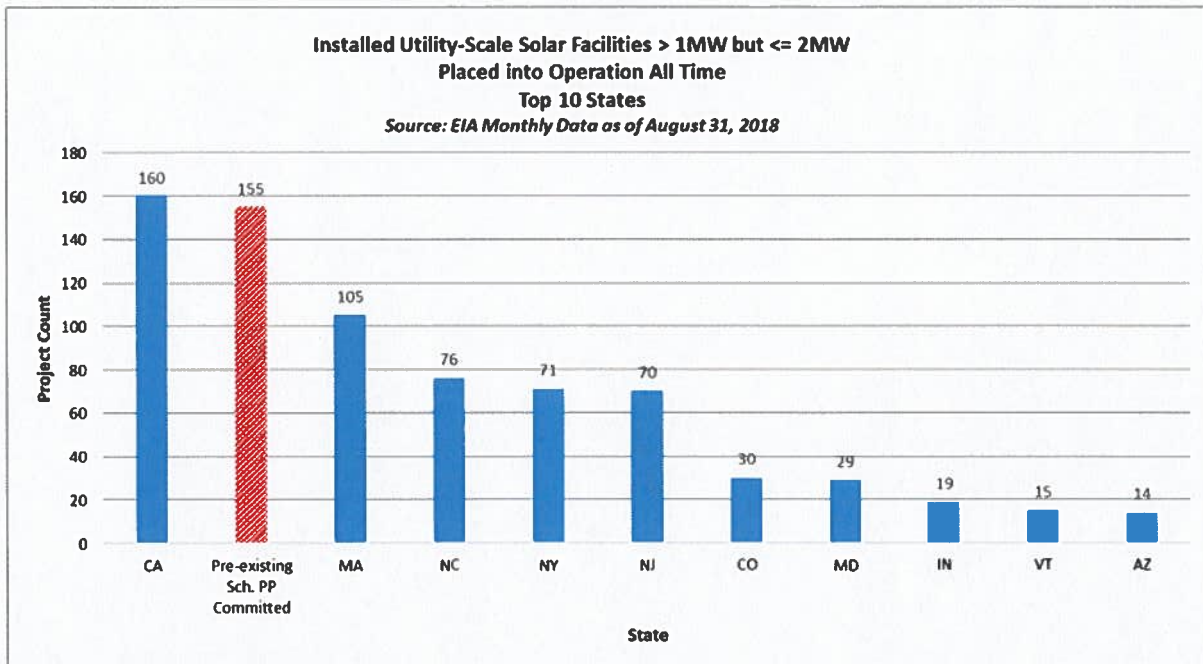
¹⁹ The United States Energy Information Administration published a report in 2016 identifying that North Carolina was leading all 50 states, including California, in PURPA-supported utility-scale solar installed capacity. See U.S. Energy

overpayment for QF power, North Carolina recently significantly scaled back its PURPA implementation framework in 2017, reducing the Companies' North Carolina standard offer eligibility from 5 MW to 1 MW and reducing the standard offer PPA term from 15 years to 10 years.²⁰

13. Assuming the QF projects that have committed to sell their output under the pre-existing Schedule PP complete development and begin delivering power, the Companies' South Carolina service territories have the potential to rapidly become a unique national leader in terms of installed 2 MW QF solar generators, which is the maximum size eligible for Schedule PP. Figure 2 presents current United States Energy Information Administration ("EIA") data showing the top 10 states for installed solar generators between 1.0 MW and 2.0 MW. Once the 22 solar QF projects currently under construction are installed, South Carolina will very likely move into the top 10 ranking for installed solar generation in this size category in 2019. Even more significantly, Figure 2 shows that if all 155 solar QFs that have committed to sell their output under the pre-existing Schedule PP rates come online over the next few years, the number of installed South Carolina QF solar generators sized between 1 and 2 MW would rank South Carolina second only to California (160 installed as of August 31, 2018) when compared to the amount of installed utility-scale solar generation in this size category across the country today. Further, such development would double the number of projects sized between 1 and 2 MW installed in North Carolina today (76 installed as of August 31, 2018).

Information Administration, North Carolina has more PURPA-qualifying solar facilities than any other state, (Aug. 23, 2016), accessible at <http://www.eia.gov/todayinenergy/detail.php?id=27632>.

²⁰ See North Carolina Session Law 2017-192, Part I (amending North Carolina's PURPA standard implementation framework set forth in N.C. Gen. Stat. § 62-156(b) to a 1 MW standard offer up to 10-year term); see also *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, NCUC Docket No. E-100, Sub 148 (Oct. 11, 2017) (implementing North Carolina Session Law 2017-192 or "HB 589" and updating DEC's and DEP's standard offer framework in North Carolina).

Figure 2

14. The Companies' experience has been that this unique and unparalleled growth of solar QF generators specifically at or just below 2 MW has been driven by the Schedule PP standard offer that has been in place since 2016.

II. OVERVIEW OF UPDATED SCHEDULE PP TARIFF, TERMS AND CONDITIONS, AND PPA

15. Through this Application, DEC and DEP are filing updated Schedule PP tariffs to more accurately reflect the Companies' avoided costs and to recognize DEC's and DEP's most current integrated resource planning needs for capacity and up-to-date forecasts of their future cost of energy over time. Consistent with the terms of pre-existing Schedule PP, the new Schedule PP and supporting Terms and Conditions are applicable to all future QFs that establish

a legally enforceable obligation (“LEO”) committing to sell the output of their QF generating facility to DEC or DEP on or after the date of this filing.²¹

16. Consistent with PURPA’s directive that avoided cost rates for purchases from QFs shall be just and reasonable to the Companies’ customers and in the public interest, the Companies also believe it is important to recognize that surging solar QF growth is creating an increasingly significant financial obligation for the Companies’ customers. The long-term financial obligation associated with the over 155 solar QFs (totaling over 300 MW) committing to sell their output under the pre-existing Schedule PP is projected to total approximately \$320 million over the next 10-12 years depending on when these QFs become operational.

17. In addition to the growing financial obligations associated with the significant solar QF development that has occurred on the Companies’ systems since 2016, the Companies have also begun to experience increasing operational challenges and cost impacts associated with the growing levels of variable, non-dispatchable utility-scale QF solar that continues to be installed in the Companies’ service territories in South Carolina and North Carolina.

a. Schedule PP Standard Offer Eligibility

18. The new Schedule PP retains the pre-existing Schedule PP size eligibility for QFs up to 2 MW that has significantly encouraged QF development in South Carolina since 2016. The new Schedule PP also continues to provide eligible QFs with variable, 5-year, and 10-year fixed term options.

²¹ See Schedule PP at 1 (describing in Paragraph 3 of the “Availability” section that the “Fixed Long Term Credit rates on this schedule are available only to otherwise eligible Sellers that establish a Legally Enforceable Obligation on or before the filing date of proposed rates in the next avoided cost proceeding” and that the Companies’ filed rates will be “subject to adjustment if different rates are approved by the [Commission]”).

b. Application of Peaker Methodology to Calculate Avoided Energy and Capacity Rates

19. The Companies have each developed their avoided capacity and energy costs using the “peaker methodology” as a reasonable and appropriate method for deriving DEC’s and DEP’s forecasted avoided costs. The Companies have consistently used the peaker methodology to calculate their avoided costs in a number of prior avoided cost proceedings before this Commission.

20. The peaker methodology is generally accepted throughout the electric industry to calculate avoided costs based upon the installed fixed cost of a peaker (*i.e.*, a combustion turbine), plus the marginal running costs of the system (*i.e.*, the highest marginal cost in each hour). Applying the peaker methodology, the cost of peaking capacity is utilized as the cost basis to calculate the avoided capacity rate. The avoided energy rates are calculated by simulating DEC’s and DEP’s respective system operations once with, and once without, 100 MW of “no cost generation” in each hour, and then comparing the two simulations. The marginal energy savings associated with the 100 MW of no-cost generation is used to determine the avoided energy rates under the peaker methodology.

c. Avoided Capacity Calculation

21. In quantifying DEC’s and DEP’s future avoidable capacity under the peaker methodology, the Companies have recognized their first avoidable capacity need in the year that each utility’s most recent Integrated Resource Plan (“IRP”) next demonstrates an avoidable capacity need.²² Pursuant to the Companies’ 2018 IRPs, DEC’s next avoidable capacity need is

²² Duke Energy Carolinas, LLC 2018 Integrated Resource Plan, Docket No. 2018-10-E (filed Aug. 31, 2018) (“DEC 2018 IRP”); Duke Energy Progress, LLC 2018 Integrated Resource Plan, Docket No. 2018-8-E (filed Nov. 1, 2018) (“DEP 2018 IRP”).

a planned 460 MW (winter rating) of combustion turbine capacity in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020.²³

22. This determination of future need for new capacity resources specifically recognizes the limited capacity value provided by solar QFs. DEC's and DEP's 2018 IRPs studied the reliability contribution of solar resources in the capacity planning process and more precisely recognized the capacity value associated with incremental, non-dispatchable solar capacity additions to the Companies' systems. Because solar output correlates more closely to summer peak demands that occur in the afternoon hours versus winter peak demands that occur in early morning hours, the resulting winter capacity contribution values for solar are significantly reduced. In addition to providing only very limited capacity value in the winter, the 2018 IRPs also recognized that as solar penetration increases, the capacity value of incremental solar additions also decreases further since the potential for firm load shed events is shifted even further into hours when there is less solar output.²⁴

23. DEC and DEP have each calculated their respective avoided capacity cost based on the cost of a simple cycle combustion turbine ("CT") unit. The Companies have also included a 1.05 performance adjustment factor ("PAF") in the avoided capacity calculation as an adjustment for the reliability equivalence of the Companies' total generation fleet. This multiplier increases the avoided capacity rate, allowing the QF to receive full capacity value if its forced outage rate is equivalent to that of the Companies' overall generation fleets.

²³ See DEC 2018 IRP, at 70, DEP 2018 IRP, at 72.

²⁴ See DEC 2018 IRP, Chapter 9, at 43-46 and DEP 2018 IRP, Chapter 9, at 44-47.

d. Avoided Energy Calculation

24. Avoided energy costs represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt-hour (“\$/MWh”), include items such as avoided fuel and avoided variable operating and maintenance (“VOM”) expenses. The peaker methodology credits the QF for avoiding energy (more specifically, fuel and VOM costs) from the most expensive unit required to serve load in any given hour, which is often referred to as the marginal unit.

25. To calculate DEC’s and DEP’s system marginal energy costs, the Companies have relied upon the PROSYM generation production cost modeling platform to derive the forecasted energy costs that a QF could avoid. The Companies have also used the same commodity price forecast methodology and VOM input assumptions that were used in developing the Companies’ recently-filed 2018 IRPs.

26. The Companies’ future, forecasted avoided energy costs over the fixed 5-year and 10-year terms of the standard offer purchase obligation are largely driven by future commodity prices and, specifically, the future cost of natural gas. The Companies’ 2018 IRPs and 10-year avoided energy cost calculations rely upon forward market price data for the 10-year period (2019-2028).

27. Natural gas commodity prices are a significant input into the avoided energy rate calculation. Just as the Companies’ customers have benefited from recent significant declines in the future price of natural gas, these declining gas prices have also caused a significant reduction in the Companies’ avoided energy costs. For example, the 10-year avoided energy rates presented in this filing reflect an approximately 40% reduction in the 10-year forecasted natural

gas prices when compared to the 10-year natural gas pricing used in the rates approved by the Commission in 2016.

28. The Companies' avoided energy cost calculations continue to recognize distribution-connected QF generation's avoidance of transmission system line losses, and therefore, the Schedule PP rates continue to include avoided energy and capacity credits that vary depending on whether the QF is interconnected with and delivering energy to the transmission or distribution system.

e. Schedule PP Energy and Capacity Credit Rate Design

29. The Companies' Schedule PP pays QFs on a volumetric basis, meaning that both avoided energy and capacity is paid on a \$/MWh basis to align the payment with actual generation performance during the entire month versus a separate fixed \$/MW payment for capacity during a specific peak hour. The rates are designed to credit QFs for avoided energy supplied during designated on-peak and off-peak hours. Energy credits are applicable to all QF energy supplied during the year and vary for the designated on-peak and off-peak hours in a day. Capacity credits are applicable to all QF energy supplied during the designated capacity payment hours.

30. Due to the recent surging solar QF growth experienced in the Companies' service territories over the past few years, the Companies have evaluated the continued appropriateness of the pre-existing rate design and determined that structural changes to both the avoided energy and avoided capacity components are needed to align with cost causation and to send more appropriate price signals to QFs. Specific to avoided energy, the Companies' recent experience as significant solar generation has been installed on the Companies' systems is that a solar profile is not coincident with peak load, and, therefore, lacks coincidence with the Companies'

highest marginal cost hours in both winter and summer. As a result, under the pre-existing rate structure, QFs were over-credited for energy during the on-peak hours. Additionally, the Companies determined that the capacity rate paid to solar QFs under the pre-existing Schedule PP should be revised to better align with the amount of avoided capacity that the solar QF generators will provide because solar QFs are intermittent, non-dispatchable, and not capable of following customer load.

31. To address these concerns, the Companies have developed more granular avoided energy and avoided capacity rate designs that better recognize the hourly value of QF energy and capacity to DEC and DEP. This new rate design provides improved price signals to more appropriately pay QFs for the value they provide.

32. The new Schedule PP avoided energy rate design designates five distinct energy pricing periods to better recognize each utility's discrete production costs throughout the day, as well as differences in summer and non-summer peak periods. The structure provides more granularity than the pre-existing Schedule PP rate design, which only offered broad, on-peak and off-peak pricing. The new Schedule PP rate design more appropriately compensates QFs for the avoided energy value they create for customers. The five energy pricing periods and their respective prices are shown on Figure 3 and are further defined in Schedule PP.

Figure 3²⁵

Filed Energy Rates																										
Independent Energy Price Blocks		1. Summer On					2. Non-Summer On (am)					3. Non-Summer On (pm)					4. Summer Off					5. Non-Summer Off				
Company Rate (cents/KWH)		DEC 4.00	DEP 3.31				DEC 4.31	DEP 3.78				DEC 3.87	DEP 3.40				DEC 2.64	DEP 2.71				DEC 2.66	DEP 2.49			
DEC		Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (May - Sep)		Off												On												Off
Non-Summer (Oct - Apr)		Off					On (am)					Off					On (pm)					Off				
DEP		Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (May - Sep)		Off												On												
Non-Summer (Oct - Apr)		Off					On (am)					Off					On (pm)									

Prior Energy Rates																										
Independent Energy Price Blocks		1. On										2. Off														
Company Rate (cents/KWH)							DEC 5.04	DEP 4.71						DEC 4.09	DEP 4.15											
DEC / DEP		Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)		Off												On										Off		
Non-Summer (Oct - May)		Off					On										Off									

Each of the five pricing periods has its own independent price (called a “price block”) to better reflect the value of QF energy during the different periods. The on-peak pricing periods were selected because they represent hours with above-average “net load” requirements, which coincide with Companies’ higher marginal energy costs during these periods. The five pricing periods also vary slightly for DEC and DEP to account for the differences in each utility’s load profile net of solar generation.

33. The new Schedule PP capacity rate design offers three distinct pricing periods, instead of the two pricing periods offered under the pre-existing Schedule PP design, to better reflect the marginal capacity value to customers during each period. The updated pricing periods offer capacity payments during the summer months of July and August and winter months of

²⁵ The periods shown in Figure 3 and Figure 4 that follow represent hour-ending convention (example: Hour 7 represents the hour from 6 a.m. to 7 a.m.).

December through March. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity to the Companies and their customers during those hours. The three capacity pricing periods are the same for DEC and DEP. Figure 4 shows the new Schedule PP capacity pricing periods (and their respective prices) compared to the capacity pricing periods under pre-existing Schedule PP. The three distinct pricing periods focus on fewer hours in the new Schedule PP and more precisely reflect the value of QF capacity. As shown in Figure 4 and discussed in Section II(c) above, DEP's higher avoided capacity payments for DEP compared to DEC is due to DEC's earlier avoidable capacity need in 2020 versus DEC's first capacity need in 2028.

Figure 4

Filed Capacity Rates																									
Independent Energy Price Blocks		1. Summer On						2. Winter On (am)						3. Winter On (pm)											
Company Rate (cents/KWH)		DEC		DEP				DEC		DEP				DEC		DEP									
		0.21		0.00				0.97		11.15				0.31		4.78									
DEC / DEP	Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jul - Aug)																			On						
Winter (Dec - Mar)								On (am)												On (pm)					

Prior Capacity Rates																									
Independent Energy Price Blocks		1. Summer On						2. Non-Summer On																	
Company Rate (cents/KWH)		DEC		DEP				DEC		DEP				DEC		DEP									
		6.68		6.27				2.58		2.43															
DEC / DEP	Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun - Sep)																			On						
Non-Summer (Oct - May)								On																	

34. The new Schedule PP rate design also reflects changes to the seasonal allocation weighting for capacity payments based on the Companies' most recent IRPs. The new seasonal allocation is heavily weighted to winter based on the impact of summer versus winter loss of load risk. As presented in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in

the winter and approximately 90% of DEC's loss of load risk occurs in the winter.²⁶ Thus, DEP's new rates pay all of its annual capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and the remaining 10% in the summer period.

f. Integration Services Charge

35. FERC's PURPA regulations clearly establish that the rates for purchase of QF power may be different depending on the characteristics of the QF generating the power.²⁷ Factors affecting the value of QF power to the utility can include the availability of the QF during system daily and seasonal peak periods, the utility's ability to dispatch the QF, and the reliability of the QF to deliver power when called upon, among others.²⁸

36. In response to the recent surging solar-only QF growth across the Companies' service territories, DEC and DEP have determined that integration of increasing levels of intermittent and non-dispatchable solar resources into each utility's generation mix results in additional costs that should be recognized in assessing the costs the utility avoids as a result of purchasing from solar QFs. To meet the Companies' obligation to provide reliable service, DEC and DEP must dispatch their fleet generation resources and purchased power resources to meet real-time load on a moment-to-moment basis. Solar capacity is variable in its daily energy output and can unexpectedly drop-off or ramp-up very rapidly in real-time, thereby increasing uncertainty in day-ahead, hourly, and sub-hourly forecasts. This additional uncertainty requires the Companies to carry additional operating reserves, which are the real-time system resources

²⁶ DEC 2018 IRP, at 45; DEP 2018 IRP, at 46.

²⁷ See 18 C.F.R. § 292.304(e); see also *California Pub. Utilities Comm'n*, 133 FERC ¶ 61,059, at P 23 (Oct. 21, 2010) (highlighting that it is appropriate to "differentiate among [QFs] using various technologies on the basis of the supply characteristics of the different technologies").

²⁸ See 18 C.F.R. § 292.304(e).

required to balance and regulate the system on an hourly and sub-hourly basis. These operating reserves are provided by reserving additional dispatchable fleet resources to ensure sufficient operational flexibility is available to respond in real-time to rapid movements in solar output. Ensuring sufficient operating reserves are available is also required to maintain compliance with NERC bulk electric system balancing and reliability standards while operating fleet resources within their lowest reliable operating limits. These increased real-time system regulation and balancing reserve requirements attributable to integrating increased levels of uncontrolled solar QF generation result in increased operating costs relative to a dispatchable generation source.

37. The Companies' new rate design includes an integration services charge to recognize the impact on operating reserves for new variable and non-dispatchable solar capacity. The integration services charge was developed based on a recently-conducted study of the current cost to provide the additional operating reserves or generation "ancillary services" needed to integrate increasing levels of solar QF generation into the DEC and DEP systems.

38. The integration services charge included in Schedule PP is designed to reflect the average integration cost for all existing and committed solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources. The \$1.10/MWh integration services charge for DEC and \$2.39/MWh integration services charge for DEP is also based only on existing and committed solar capacity in DEP (2,950 MW) and DEC (840 MW) across each utility's respective system. The difference in the DEP and DEC cost is largely driven by the significantly greater amount of existing and committed future solar capacity in DEP compared to DEC.

39. The integration services charge will apply only to new solar generators coming onto the system, which would include solar QFs that sell power to the Companies under the

avoided cost rates filed in this proceeding. The Companies are not proposing to apply this charge to QFs that established LEOs but have not yet entered into PPAs under the pre-existing Schedule PP. Over time, as existing contracts expire and new contracts are executed, this average integration charge will apply to all solar providers uniformly. The Companies plan to continue to study the cost to integrate operating and incremental solar generation and will update the Commission in the future on changes to the integration costs. Factors such as solar penetration levels, prevailing fuel prices and the makeup of the Companies' future resource portfolios will all be taken into consideration in assessing the then-prevailing integration costs. The Companies plan to update the integration services charge as part of future avoided cost filings. As described in the Rate Updates section of Schedule PP, any future Commission-approved adjustments to the integration services charge would apply to QFs contracting under new Schedule PP.

g. Modifications to Schedule PP PPA and Terms and Conditions.

40. The Companies have amended Schedule PP to reflect the updated rates and terms supported in Section II (a) through (f) above and are amending the standard Schedule PP PPA and Terms and Conditions to incorporate the following amendments in response to the recent significant QF development under Schedule PP and current economic and regulatory circumstances relating to PURPA implementation in South Carolina.

41. The Companies have amended Paragraph 14 of the Terms and Conditions to provide greater clarity around the circumstances that are considered "an emergency condition." These circumstances expressly include any circumstance that requires action by the Companies to comply with NERC/SERC regulations or standards. The Companies are also amending Paragraph 2(b) of the Terms and Conditions to make clear that QFs delivering power under

Schedule PP must comply with any Duke Energy system operator instructions and operational protocols for dispatching generation (or battery storage) output on to the system.

42. The Companies have additionally amended Paragraph 1(e) of their Terms and Conditions to clarify that PPAs shall not be transferred and or assigned by a QF or “Seller” under the PPA to any person, firm, or corporation that is a party to any other PPA under which it sells or seeks to sell power to the Companies as a QF, if that party is located within one-half mile of the original QF. This clarification relates to the availability of the Companies’ Schedule PP. The pre-existing Schedule PP is not available to a QF that sells power to the Companies from another affiliated QF located within one-half mile, unless the combined capacity is equal to or less than 2 MW. The proposed amendment to the Terms and Conditions is intended to clarify this existing provision and to prevent evasion of this geographic restriction through subsequent consolidation of ownership of QFs after their Schedule PP PPAs have been executed.

43. The Companies have also amended their Schedule PP PPAs to address circumstances in which an operating QF may seek to modify the generating facility to increase its AC capacity or DC (energy) output under the PPA. A QF that has entered into a Schedule PP PPA with the Companies and subsequently requests to modify the generating facility to increase output has the right to make such a request under the PPA subject to generally-applicable requirements related to continued QF certification and Schedule PP eligibility requirements²⁹ and any needed interconnection review, as determined by DEC or DEP, to ensure grid safety and reliability are maintained. However, any such increase to the QF’s “Contract Capacity” under the Schedule PP PPA and Section 4 of the Terms and Conditions *will not* be allowed if the QF

²⁹ For example, solar QFs up to 80 MW_{AC} qualify as small power producer QFs.

seeks to retain its pre-existing standard offer PPA at the Companies' pre-existing and now stale and significantly higher avoided cost rates. Any such action by the QF would constitute a modification to the QF "Facility"³⁰ that has committed to sell power to DEC or DEP under the then-effective PPA and an event of default resulting in termination of the PPA, at the Companies' election. Section 1.4 of the Companies' standard offer PPA establishes the "Contract Capacity" of the QF (measured in kW/MW_{AC}) and requires the QF and the Companies to agree to an estimated annual energy production, which represents "the amount [of energy] Seller contracts to deliver to the Company and Company agrees to receive." The Companies have modified Section 1.4 of the Schedule PP PPA and Section 4 of the Terms and Conditions to state clearly that QFs are not permitted to add additional capacity or other equipment to the operating Facility that would increase the DC or AC output of the generating facility. The Companies are clarifying their current position under the standard offer PPA and Terms and Conditions to avoid future disputes and to avoid increasing the current over-payment obligation to QFs in excess of today's avoided costs.

44. The Companies are also making certain other ministerial and clarifying modifications to Schedule PP, their respective Terms and Conditions, and PPAs.

³⁰ The description of the "Facility" from which the Companies are contracting to purchase output is a material term of the PPA that is defined in the PPA to include the nameplate capacity, fuel type, and physical location of the QF. Any unilateral attempt to further modify the PPA, including a material modification of the design, description, or capability of the "Facility" would constitute a breach of contract against the party attempting the modification, giving rise to a termination right.

III. SUMMARY OF EXHIBITS SUPPORTING APPLICATION

45. DEC and DEP each submit for filing and approval proposed standard avoided cost rates for qualifying cogeneration and small power production facilities, as further discussed and supported herein.

- **DEC Exhibit 1** presents a redlined copy of DEC's Purchased Power Schedule PP.
- **DEC Exhibit 2** presents a clean copy of DEC's Purchased Power Schedule PP.
- **DEC Exhibit 3 (Confidential)** presents the supporting calculations used to derive the avoided energy and avoided capacity rates. Information included in Exhibit 3 is designated Confidential and is being filed under seal.
- **DEC Exhibit 4** presents a redlined copy of DEC's Standard PPA available to QFs eligible for Schedule PP.
- **DEC Exhibit 5** presents a clean copy of DEC's Standard PPA available to QFs eligible for Schedule PP.
- **DEC Exhibit 6** presents a redlined copy of DEC's Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions").
- **DEC Exhibit 7** presents a clean copy of DEC's Terms and Conditions.

DEP Exhibits 1-7 present the same information for DEP as described above for DEC.

DEP Exhibit 3 is also designated Confidential and is being filed under seal.

IV. REQUEST FOR PROCEDURAL ORDER

46. The Companies respectfully request that the Commission issue a procedural order establishing dates for the filing of testimony and exhibits by the Companies and other interested

parties. Consistent with this request, the Companies respectfully propose the following procedural schedule for the Commission's consideration:

1. That the direct testimony and exhibits of the Companies be filed on or before January 18, 2019;
2. That the direct testimony and exhibits of intervenors be filed on or before March 26, 2019;
3. That any rebuttal testimony and exhibits of the Companies shall be filed on or before April 23, 2019;
4. That any surrebuttal testimony and exhibits of intervenors shall be filed on or before April 30, 2019; and
5. That an evidentiary hearing be scheduled at the Commission's discretion, in consultation with the parties. The Companies have consulted with ORS, and ORS is agreeable to this procedural schedule.

WHEREFORE, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission approve the Companies' respective Schedule PP, Schedule PP PPA, and Terms and Conditions, grant the Companies' request to maintain the information contained in DEC Exhibit 3 and DEP Exhibit 3 as confidential, and to provide any further relief the Commission deems to be just and reasonable and in the public interest.

This, the 30th day of November, 2018.



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Progress, LLC*

VERIFICATION

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

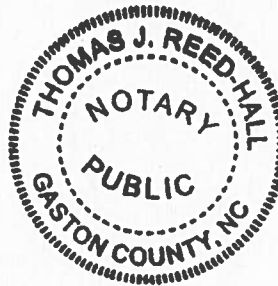
GLEN ALLEN SNIDER, being first duly sworn, deposes and says:

That he is Director – Integrated Resource Planning and Analytics – Carolinas; that he has read the foregoing Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Updated Standard Offer Avoided Cost Rates and Tariffs and knows the contents thereof; that the same are true of his own knowledge, that the same is true as to matters stated therein on information and belief, and as to those matters, he believes them to be true.


Glen Allen Snider

Sworn to and subscribed before me
This 27 day of November 2018.


Notary Public



My commission expires: 7-30-2022